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Evaluating Levelized Cost of Storage (LCOS) Based on Price Arbitrage Operations: with Liquid Air Energy Storage (LAES) as an Example

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Abstract

Liquid air energy storage (LAES) is a novel proven technology that can increase flexibility of the power network, obtaining revenue through energy price arbitrage. To assess the economic potential of a variety of energy storage options, this study develops a cost research framework for LAES, which is also applicable to other energy storage technologies. For the calculation of Levelized Cost of Storage (LCOS), it is essential to evaluate the electricity purchasing cost and the total electricity generated. However, they are often estimated by simply assuming an average electricity price and an annual operating cycle in the previous studies. In this paper, a price arbitrage algorithm is developed, according to which decisions are made at each time step whether to charge, discharge or stand by. Thus, the electricity purchasing cost as well as the amount of electricity generated by the storage unit is determined and the LCOS of the energy storage system is calculated. Results show that the LCOS for a 25MW/125MWh LAES system is in the range 191-590 £/MWh, depending on different round-trip efficiencies and different costs set in three scenarios. If the round-trip efficiency is assumed to be 60%, the LCOS would in the range 191-294 £/MWh under the three scenarios.

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Keywords: Levelized Cost of Storage (LCOS); Liquid Air Energy Storage (LAES); Price Arbitrage

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1. Introduction

Electricity generation from renewable sources has grown rapidly due to the promotion of clean energy policies in many countries. This presents challenges to the grid when the supply is from variable sources, such as wind and solar. In order to integrate large amounts of intermittent generation into the grid, Arani et al. [1] and many others have suggested that Electrical Energy Storage (EES) is a potential solution for increasing flexibility and thus the penetration of renewable on the power network.

Antonelli et al. [2] argued that an ideal EES technology to cope with the increasing deployment of renewable electricity generation on electricity grids should have a high power rating, a large storage capacity, high efficiency, low costs and no geographic constraints. As mentioned by Rodrigues et al. [3] and Guizzi et al. [4], to date only two technologies are considered mature for grid-scale energy storage: Pumped Hydro Energy Storage (PHES) and Compressed Air Energy Storage (CAES).

Traditionally, PHES is used for large capacity storage due to its maturity and low cost per stored MWh, argued by Rastler [5]. However, the capacity for using large-scale water reservoirs has reached its limit in many developed countries due to geographic and environmental constraints according to Ameel et al. [6]. Similarly, specific geographical conditions are also required for the application of large-scale underground CAES, and to date, as reported by McGrail et al. [7] and IRENA [8], there are only two such grid-scale CAES plants that have been demonstrated in operation: a 110 MW plant in McIntosh, Alabama and a 290 MW plant in Huntorf, Germany. Due to the drawback that their application is constrained by geological features, considerable effort has been made to find other EES approaches that can provide large scale, cost-efficient solutions without such constraints.

Compared to CAES which stores air as a gaseous phase, a much higher energy density can be achieved by liquid air energy storage (LAES) that stores air in its liquid phase (Ameel et al. [6], Ding et al. [9]). LAES uses liquid air as a storage medium and includes three distinct processes: charge, storage and discharge (Figure 1). The features of LAES include: 1) it is a grid-scale energy storage system using established technology with no geographic constraints; 2) the effective round-trip efficiency of the LAES system can be improved significantly by the utilization of external heat/cold through integration with other systems such as thermal power plants or a LNG regasification facilities; 3) there are three physically separate components which can be independently sized, making it possible to optimize the LAES system for different applications.

LAES has drawn increasing attention in the UK since the 300 kW/2.5 MWh pilot scale plant, built by Highview Power Storage, started operations in 2010 (Brett [10]), now in use at the University of Birmingham (Sciacovelli [11]). In April 2018, Highview's 5 MW/15 MWh demonstration plant started operation. It is located alongside the Pilsworth landfill gas generation site in Bury, UK, from which it obtains low grade waste heat and therefore increases the effective round-trip efficiency of the system.

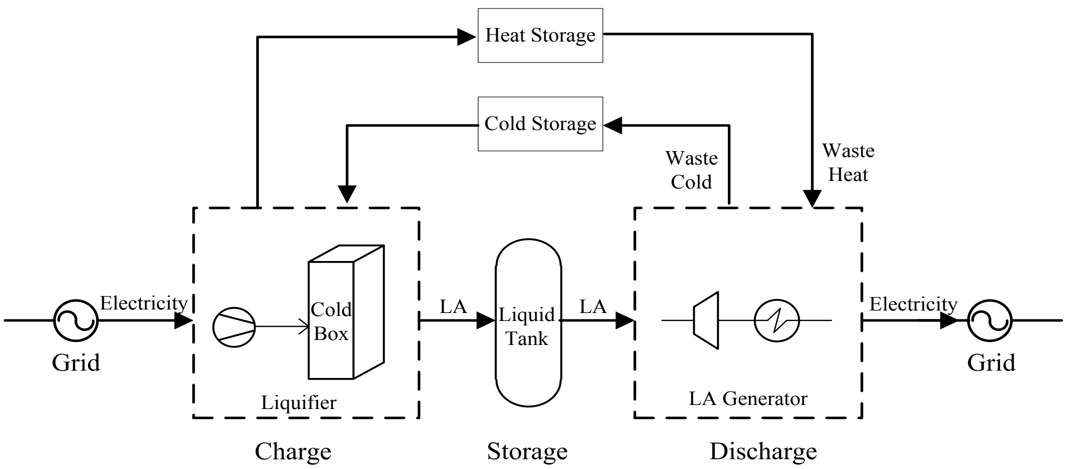

Figure 1: Schematic diagram of a LAES system.

Existing literature regarding LAES is mostly focusing on its technical performance. Krawczyk et al. [12] presented a thermodynamic analysis of a LAES system and a CAES system, and argued that one advantage of the LAES over the CAES is the significantly lower volume needed for energy storage. Peng et al. [13] conducted a thermodynamic study on the effect of cold and heat recovery on the performance of LAES and found that the cold energy has a much significant effect on the round-trip efficiency of LAES than the heat energy. She et al. [14] studied the possibilities of improving the round-trip efficiency of LAES through effective utilization of heat of compression and their thermodynamic analyses showed that the round-trip efficiency could be enhanced 9-12% by using the excess heat of compression as a heat source to power an organic Rankine cycle. Peng et al. [15] analyzed the performance of a LAES system with packed bed units and according to their results, a LAES system may probably be considered as a viable option for grid-scale (>100 MW) electric energy storage. Similar studies include She et al. [16], Borri et al. [17], Hüttermann et al. [18] and many others. However, cost research on LAES is very limited.

Although there are many techno-economic analyses focusing on other energy storage technologies, Kapila et al. [19] argued that the economic assessment remains obscure in most of the studies, and many techno-economic ESS studies only give information on the unit capacity capital cost (how much per kW or per kWh) for the energy storage plant without any detailed cost analysis. To fill this gap and provide an assessment of the economic potential of a variety of EES technologies, this study develops a cost framework which combines the existing summary cost metric of Levelized Cost of Storage (LCOS) with a price arbitrage algorithm, taking LAES as an example.

Nomenclature

CAES	Compressed Air Energy Storage
EES	Electrical Energy Storage
FOAK	First-Of-A-Kind
LAES	Liquid Air Energy Storage
LCOE	Levelized Cost of Electricity
LCOS	Levelized Cost of Storage
PHES	Pumped Hydro Energy Storage
I_0	Capital Expenditure for Investment
TC_t	Annual Total Costs at Year t
$EOUT_t$	Annual Electricity Outputs at Year t
n	Lifetime of the Plant
i	Discount Rate
OPEXE	Annual Energy Based Operating Expense
OPEXP	Annual Power Based Operating Expense
EC	Annual Electricity Purchasing Cost
IC	Annual Insurance Costs for All System Devices
P_n	Electricity Price at Time Step n
EINn	the Amount of Electricity Charged at Time Step n
P_{h_ths}	Upper Price Threshold
P_{l_ths}	Lower Price Threshold
T_D	Discharging Time
T_C	Charging Time
MP_D	Marginal Price for Discharging
MP_C	Marginal Price for Charging
η	Round-trip Efficiency of the LAES Plant
POW_D	Power Rating for Discharging Unit
POW_C	Power Rating for Charging Unit

2. Methodology

The method of Levelized Cost of Energy (LCOE), which is defined as the total lifetime cost of an investment divided by the cumulated generated energy by this investment, has been applied by many academic studies, such as Pawel [20], Bruck et al. [21] and Tran et al.[22], and widely used in policy-making (e.g. [23]). Similar to the calculation of LCOE and based on net present value method, LCOS can be written as Eq. (1), in which the total cost over the entire lifetime of the plant is divided by the total amount of electricity generated by the storage system.

$$LCOS = \frac{I_0 + \sum_{t=1}^{t=n} \frac{TC_t}{(1+i)^t}}{\sum_{t=1}^{t=n} \frac{EOUT_t}{(1+i)^t}} \tag{1}$$

Where I_0 denotes the capital expenditure for investment, TC_t stands for the annual total costs at year t, $EOUT_t$ represents the annual electricity outputs, and n is the lifetime of the plant. Both the annual costs and the annual electricity outputs are discounted with the interest rate i (please refer to [24] for more detailed explanations).

To evaluate the annual cost TC, we take into consideration: 1) the annual energy based maintenance expense, OPEXE; 2) the annual power based operating expense, OPEXP; 3) the annual electricity purchasing cost, EC; 4) the insurance costs for all the devices, IC. Due to the long lifetime and great uncertainty, the residual value for system components at the end of the storage lifetime is assumed to be zero. Therefore, TC can be calculated by:

$$TC = OPEXE + OPEXP + EC + IC \tag{2}$$

To estimate the annual electricity purchasing cost, Jülch [24] and Smallbone et al. [25] assumed an average electricity price of €3ct/kWh for all EES technologies, and multiplied it with the annual electricity input. The annual electricity input is obtained by assuming a certain amount of discharging cycles per year. For example, Smallbone et al. [25] assumed a pumped heat energy storage system operating at two cycles per day and thus 14,600 cycles over the lifetime of 20 years. As a result, the LCOS obtained is strongly dependent on the number of storage cycles and the electricity price. However, these two variables are exogenous in their analysis, which could lead to unreliable results.

In order to overcome this drawback, this paper incorporates price arbitrage operations into the LCOS calculation, which means the arbitrage possibilities are different seen by different EES technologies (the assumption of an average electricity price means ignoring their diversities on arbitrage capability). In this paper, a price arbitrage algorithm is developed, based on the UK's half-hourly electricity spot prices in 2015, according to which decisions are made at each time step n (the n^{th} half hour) whether to charge, discharge or stand by. This price arbitrage algorithm aims at finding the maximum potential arbitrage revenue for an EES technology of a certain size. Thus, the annual electricity purchasing cost EC is calculated by:

$$EC = \sum_{n=1}^{17520} P_n * EIN_n \tag{3}$$

Where P_n denotes electricity price at time step n; while EINn implies the amount of electricity charged at time step n. In other words, determined by the price arbitrage algorithm, the electricity purchasing cost is calculated for every half-hour when a charging decision is made.

As shown in Figure 2, the main purpose of the arbitrage algorithm is to determine a high price (upper threshold) P_{h_ths} and a low price (lower threshold) P_{l_ths} within a certain time period, which enables a maximum potential arbitrage revenue when selling electricity at price P_{h_ths} and buying electricity at price P_{l_ths}. The arbitrage optimization process is described as follows:

a) For all prices within a selected time period, sorting from the lowest price to the highest price, thus an increasing sequence is obtained as:

$$P = [p_1, p_2, \ \ldots\ldots p_n] \tag{4}$$

b) For the discharging time T_D, giving it the initial value 1:

$$T_D = 1 \tag{5}$$

c) Finding the corresponding marginal price for discharging:

$$MP_D = P(n - T_D + 1) \tag{6}$$

For example, when T_D=1, then MP_D=P(n), suggesting the system will only discharge at the time step with the highest electricity price).

d) To maintain a balanced level of stored liquid air, the charging time T_C is determined by the amount of liquid air needed for discharging:

$$T_C * \eta * POW_C = T_D * POW_D \tag{7}$$

Where, η denotes the round-trip efficiency of the LAES plant, POW_C and POW_D represent the power rating for charging unit and discharging unit, respectively.

e) Finding the corresponding marginal price for charging:

$$MP_C = P(T_C) \tag{8}$$

f) Examining whether there is room for arbitraging, based on Equation (9):

$$MP_D \geq MP_C / \eta \tag{9}$$

If the above inequality holds, which means there is still further room for arbitraging, then set the charging time to T_D=T_D+1 and repeat steps c) to f).

Otherwise the price thresholds are determined by:

$$P_{h\_ths} = P(n - T_D); \ P_{l\_ths} = MP_C \tag{10}$$

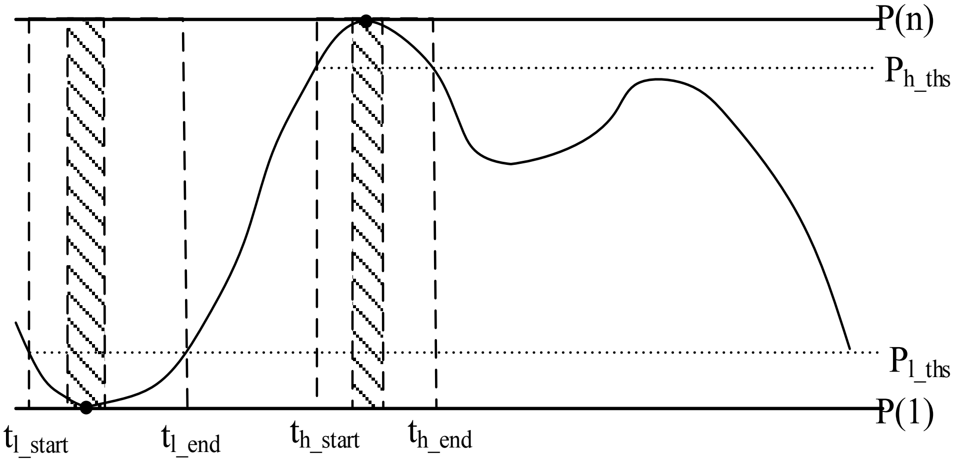

Figure 2: An illustration describing the arbitrage operation algorithm.

As described in Table 1, a commercial scale of LAES plant is considered in this analysis, with charging power of 17MW, discharging power of 25MW and a storage capacity of 125MWh.

Table 1. Target size for the proposed commercial plant.

Input variable	Value
Liquefier power	17 MW
Turbine power	25 MW
Storage capacity	125 MWh
Footprint	90m*30m
Lifetime	30 years
Location	No constraint

The corresponding technical details are defined in Table 2, based on which the capital expenditure is summarized in Table 3.

Table 2. Summary of the main system components.

Input variable	Value
Power turbine	27 MW nominal shaft
Main generator	30MVA nominal
Main air compressor	5.5MW
Recycle air compressor	11.5MW
Cryogenic pump	2MW
Cryogenic storage	1,100 tonnes (equivalent to 125MWh)

The key input data for the LCOS calculation are summarized for the proposed commercial system as Table 3. Three scenarios are set: scenario 1 represents a best case scenario with the lowest capital expenditure and highest round-trip efficiency; scenario 3 represents a conservative scenario with the highest capital expenditure and lowest round-trip efficiency; while scenario 2 implies an average case between the two extreme scenarios. All financial data is given in £2015 values.

Table 3. Summary of the input data for the LCOS calculation based on three scenarios.

Input variable	Unit	Scenario 1 (lowest cost, future potential)	Scenario 2 (average, current estimation)	Scenario 3 (highest cost, conservative estimation)
Round-trip efficiency	%	60 [26]	55	50
Liquefier lifetime	years	30 [26]	30	30
Storage tank lifetime	years	30 [26]	30	30
Turbine lifetime	year	30 [26]	30	30
Self-discharge rate	% per day	1 [25]	1	1
Discount rate	%	4 [26]	4	4
Capital expenditure for the liquefier	£/kW	1000 (10^{th}-of-a-kind [27])	1450	1900 (FOAK [27])
Capital expenditure for the turbine	£/kW	245 (10^{th}-of-a-kind [27])	354	464 (FOAK [27])
Capital expenditure for storage tanks	£/kWh	23 (10^{th}-of-a-kind [27])	25	27 (FOAK [27])
Power based operating expense	£/kW	0.0023 [25]	0.0023	0.0023
Energy based operating expense	£/kWh	9.7 [25]	9.7	9.7
Insurance rate	% of I_0	0.5 [24]	0.5	0.5

3. Results and conclusions

Figure 3 shows the LCOS for a commercial LAES system with input power of 17MW, output power of 25MW and a storage capacity of 125MWh, which means charging time of 7.4 hours and discharging time of 5 hours. It is observed that the LCOS could be as high as 590 £/MWh under the conservative estimation (scenario 3); however, this number drops dramatically to 191 £/MWh under scenario 1, implying great potential of this technology.

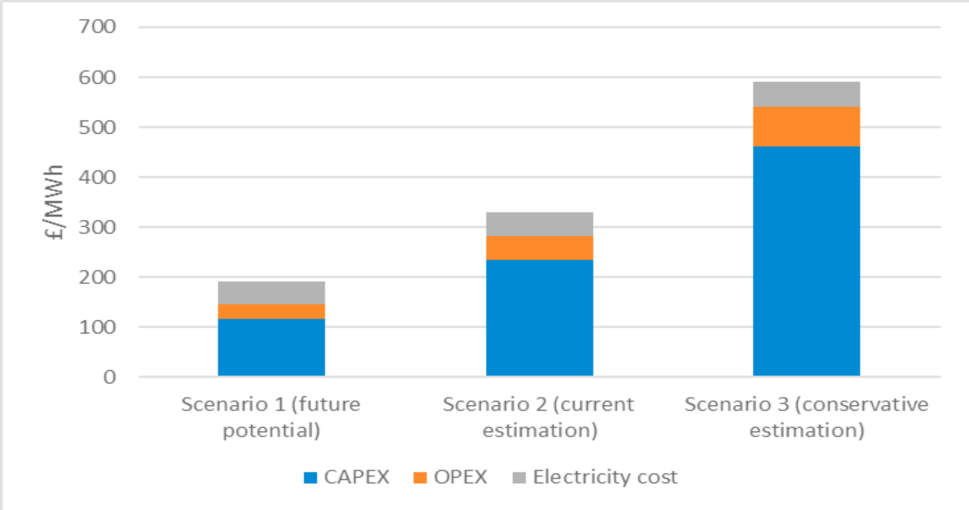

Figure 3: Composition of the LCOS for the proposed commercial LAES plant.

By assuming the same round-trip efficiency of 60% for the three scenarios, the LCOS ranges from 191 £/MWh to 294 £/MWh for a 25MW/125MWh LAES system (Figure 4). In other words, under scenario 2, the LCOS would drop from 330 £/MWh to 242 £/MWh if the round-trip efficiency increases from 55% to 60%. Similarly, under scenario 3, the LCOS declines significantly from 590 £/MWh to 294 £/MWh when the round-trip efficiency improves from 50% to 60%. Thus, the conclusion can be drawn through comparing Figure 4 with Figure 5, that the round-trip efficiency of the system has a significant impact on the LCOS.

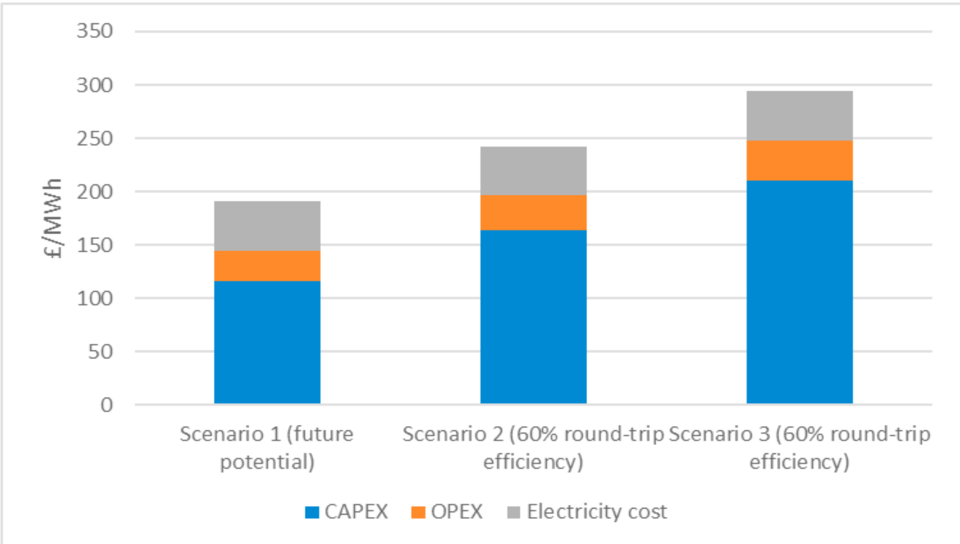

Figure 4: Estimation of the LCOS for the three scenarios with a same round-trip efficiency of 60%.

Table 4 provides an explanation for how the round-trip efficiency can affect the LCOS of the system. As mentioned before, the existing analysis on the LCOS calculation are based on a given average electricity price. For example, Jülch [24] and Smallbone et al. [25] assumed an average electricity price of €3ct/kWh for all EES technologies. However, the electricity cost seen by different energy storage systems should be different, depending on their arbitrage capabilities. As can be observed from Figure 3, the average electricity purchasing price is 27.8 £/MWh for a 25MW/125MWh LAES system with a round-trip efficiency of 60%, decreasing to 24.2 £/MWh for a system with a round-trip efficiency of 50%. The higher round-trip efficiency thus provides more revenue-earning arbitrage opportunities each year.

Table 4. Arbitrage potential for a 25MW/125 MWh LAES system with different round-trip efficiencies.

Input variable	Unit	Scenario 1 (future potential)	Scenario 2 (current estimation)	Scenario 3 (conservative estimation)
Round-trip efficiency	%	60	55	50
Annual operating cycles	-	144	109	79
Annual electricity purchased	MWh	21650	16371	11798
Annual electricity cost	£	600816	427857	285180
Average electricity purchasing price	£/MWh	27.8	26.1	24.2

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